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SETTING THE STANDARD FOR SERVICE AND SECURITY

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OFFSHORE SPECIAL EDITION

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Welcome to the fifth Offshore edition of the *Standard Bulletin*. This is a special year for Standard Offshore, as it has been 10 years since the club first set up a dedicated team to handle our offshore business. 2000 was also the year we held the first Offshore Forum, a half-day seminar for 19 people held in the boardroom at the Standard Club's office at International House. This year we will welcome over 70 guests to the 10th Offshore Forum in the considerably grander surroundings of Trinity House. They will include many representatives of a much expanded book of Standard Offshore business which, like the Forum, has grown considerably in the intervening decade, from around 4m gt to 12m gt today.

Both the club and the offshore oil and energy business have seen a great deal of change in those 10 years. The club has grown in tonnage terms and is now the largest it has ever been, with 110m gt entered of which the offshore book makes up 11%. Since 2006, the offshore business has been handled by a specialist Offshore Syndicate, and as of last year, floating production storage and offloading vessels (FPSOs) and drilling units entered with the club are insured under their own standalone Standard Offshore Rules, designed specifically for our members who operate in the offshore oil and gas exploration and production industry. Since 2008 we have also issued over 100 of our 'limited' Bunkers Blue Cards to enable our members who own and operate FPSOs, drilling rigs and floating storage vessels (FSUs) to comply with the requirements of the Bunkers Convention.

For our clients and others involved in the offshore business it has been an eventful decade. We saw the price of oil increase from around $30 per barrel in 2000 to its 2008 peak of an incredible $145 a barrel, and drop back down to $78 a barrel at the time of writing. Partly thanks to the rise in oil prices which have made field developments in the most challenging areas possible, oil companies have succeeded in accessing fields in deepwater and other previously inaccessible areas via the development and utilisation of cutting edge technologies. Sadly, the decade has also seen its share of accidents, from the sinking of the *P36* through the devastation wrought in the Gulf of Mexico by Hurricane Katrina to the blowouts suffered by the Montara and Macondo wells.

The insurance markets have had to respond to these and other large losses, as well as to deal with the damage done to their reserves by the financial hurricanes of 2008. Despite this the Standard Club entered the 2010 year in excellent shape, with free reserves of $243m at their highest level ever and with its Standard & Poor's A rating intact. Over the last decade we have worked hard to refine and improve the product we offer our members, and we believe that it is second to none in the market in terms of financial security and breadth of expertise. Without a crystal ball we cannot predict what the coming decade will bring to the club and our offshore members, but we can say with certainty that there will be both challenges and opportunities and that the Standard Club will continue to work with its membership to enable them to meet both with confidence.

OFFSHORE ENERGY INSURANCE – WHERE NEXT?

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Photo of Deepwater Horizon

The Offshore Energy sector over recent years has provided underwriters with a rollercoaster ride of performance, with adjacent years of significant loss and profit. The market performance has demonstrated the volatility of a class that has to deal with a portfolio imbalanced by large values and a concentration of risk in areas of catastrophe activity. For this reason, the business model for Offshore Energy insurance, with its estimated worldwide premium base of $3bn, looks both fragile and under threat.

Since 2005, the market has witnessed significant loss-making years, in particular, 2005 and 2008, which were both affected by hurricane losses in the Gulf of Mexico. Furthermore, following the sinking of the *Deepwater Horizon* drilling unit and the subsequent blowout of the Macondo well in April 2010, it is anticipated that 2010 will now join this roll-call of significant loss years. It is accepted that these loss-making years have been punctuated by years of reasonable profit; however, 2006 has been the only star performer. Furthermore, the marginal profit made in 2009 was largely propped up by a very benign Gulf of Mexico windstorm season, which managed to just offset the losses elsewhere in the portfolio.

As a summary, it is estimated that global market incurred loss ratios (net of acquisition costs but before reinsurance) are as follows:

	Incurred Loss Ratio
2000–2009	101%
2005–2009	105%

Therefore it is evident that Offshore Energy underwriting since 2000 has been an exercise in capital destruction. To achieve an acceptable return in this class of business, there has to be a fundamental change in the underwriting dynamics.

It is possible that the market has resolved the issue of Gulf of Mexico hurricane insurance. The re-engineering of the account in 2009, with significant price and retention increases, coupled with coverage restriction, has created the theoretical (and hopefully to remain untested in 2010) position of account sustainability in the Gulf of Mexico. However, the problem now appears to lie elsewhere – that being in the balance of the portfolio. During 2009, the two largest insured risk losses since *Piper Alpha* in 1988 occurred: the Ekofisk collision ($1bn) and the *West Atlas/*Montara well ($0.75bn) blowout. This was compounded earlier this year with the *Deepwater Horizon/*Macondo well loss, with an insured loss forecast of between $1.5bn and $3.5bn.

It is expected that the reinsurance market, driven by these losses and the likely increase in retrocessional costs, will be uncompromising during the 2011 renewal negotiations, with significant increases in both pricing and retention levels. In some cases, it is anticipated that the double pressure of the increasing severe loss frequency, coupled with the demands of the reinsurance market, will force withdrawals from the class of Offshore Energy insurance. All this is against a 2010 hurricane forecast that is 'above average' and has already been heralded by the appearance of the first June hurricane since 1995, namely Hurricane Alex.

Taking all this into account, underwriters are facing a crossroads. Failure to act in a decisive and robust manner will drive away the capital providers. The Offshore Energy sector requires a significant increase in worldwide premium base to ensure that the increasing loss frequency and severity is managed, and that an appropriate and sustainable return on capital is delivered.

In the immediate aftermath of the *Deepwater Horizon/*Macondo well loss, it does appear that the market is grasping the severity of the situation. Rate increases are being applied across the portfolio, with areas of significant risk such as deepwater drilling attracting further rating loads. The timing of the loss, occurring before the busy mid-year renewal season, has ensured that a significant element of the 2010 portfolio has been impacted by these rates rises. It is imperative that this market momentum is maintained into 2011 and beyond. If the market hesitates in its resolve, it is quite possible that the bond between capital providers and underwriters will be broken for good.

MANAGING CONTRACTUAL EXPOSURES

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The club is always available to help members in assessing whether their contract terms are drafted to properly protect the member's position.

The Standard Club offers a contract review service which aims to proactively advise members involved in the offshore oil and gas industry of the effect of the contractual arrangements they have concluded in terms of their P&I cover, including any extra extensions to cover that the contract liabilities may require. The club's intention is to provide a level of comfort in terms of the member's cover before any potential liabilities arise. During the 2009 policy year, we reviewed nearly 400 contracts covering all types of offshore operations, from EPIC (engineer, procure, install and commission) and operating contracts for FPSOs (floating production storage and offloading vessels), through drilling and construction contracts, to numerous supplyboat charterparties. Most of these contracts are relatively straightforward, but we do see a number of common issues that arise again and again, and that can lead to members finding themselves in a position where their insurance cover and their contractual liabilities may not match up. The intention of this article is to draw some of these issues to readers' attention in the hope of making them more easily avoided in the future.

CAR/EED INSURANCE

One area that often causes confusion is a lack of understanding as to the interaction between the various insurances that respond to the liabilities incurred in offshore operations. Most offshore operations involve an oil company or companies, either as the direct or the ultimate client of the shipowner, and many of the liabilities that the shipowner can potentially incur during these operations should most appropriately fall on the oil company's insurance programme. For instance, offshore construction projects are normally covered under a Construction All Risks (CAR) insurance, which is purchased by the oil company client to respond to physical loss or damage to the permanent property being installed. Energy Exploration and Development (EED) insurance responds to exposures incurred in respect of pollution and control of well during drilling or workover operations or the operating phase of an FPSO contract, and again, is normally purchased by the oil company operator.

Offshore P&I cover is not designed to respond to these risks, since they are insured under very different terms and rating arrangements, and indeed, the exclusions in the Standard Club's rules in respect of offshore risks are intended to dovetail with the cover offered under CAR and EED insurances. The 'contract works' exclusion to P&I cover refers to the project property insured under a CAR policy, whilst the Standard Offshore rules contain exclusions in respect of control of well costs and seepage and pollution from the well, wellheads and subsea equipment, which are exposures insured under an EED policy.

EXCLUDED RISKS

Problems arise when a shipowner involved in offshore operations takes on liability under a contract or fails to obtain a sufficiently watertight indemnity (which often amounts to the same thing) for risks that are most appropriately covered under CAR or EED insurances. For instance, during a floatover operation, a topsides module will be installed on a jacket, both of which are excluded from club cover under the Standard Club's definition of contract works. In order to protect himself from liability, the shipowner will need to make sure that he obtains an indemnity from his contracting partner for damage to the topsides and the jacket, both of which should be covered under the CAR policy. Any liability that the owner has for such damage is excluded from club cover as a contract works exposure, whether incurred under contract or otherwise. It is practically speaking impossible to purchase an extension to P&I cover for damage to contract works, so an owner should ensure that he contracts on terms that sufficiently protect him, or he may find himself in a position where he is without insurance cover for a very significant level of risk. Owners of drilling units and FPSOs who are insured under the Standard Offshore rules should similarly check that they are indemnified by their contracting partners for risks that fall within the Offshore rules' exclusions, such as control of well expenses and liability in respect of pollution from the reservoir and subsea systems.

EXCEPTIONS TO THE INDEMNITY REGIME

When entering into offshore contracts, members should ensure that liability and indemnity provisions are drafted so as to prevail over other contract terms, and that they will apply in all circumstances regardless of the cause of a loss. It is not uncommon for contractual indemnities to apply regardless of the negligence of the party to be indemnified, save where the loss in question is caused by that party's own gross negligence or wilful misconduct. This may seem like a benign amendment since most owners do not believe that they or their employees would be guilty of either gross negligence or wilful misconduct, but it nevertheless creates a hostage to fortune in that it introduces an element of subjectivity into what should be a completely objective knock-for-knock liability matrix. In the aftermath of a large incident, it is more than likely that the parties will resort to litigation to try to avoid liability and any possible contractual loophole will be exploited. The decision as to whether particular behaviour falls to be considered as either grossly negligent or as wilful misconduct will be made by a court, which may well be in the jurisdiction where the incident took place, and, particularly where an incident involves loss of life or substantial pollution, there may be a perceived desire to see the 'guilty party' held liable. In such circumstances, gross negligence or wilful misconduct exceptions to indemnity clauses may well be used so as to deny an owner the benefit of an indemnity upon which he might otherwise have expected to rely. This is a risk that is all the more serious since many of the losses for which owners are indemnified under offshore contracts are not covered by P&I insurance, as mentioned above.

We have recently seen some contracts dealing with offshore construction projects that refer to the requirements of the Warranty Surveyor and to the QA/QC (Quality Assurance/Quality Control) provisions of the CAR insurance and state that the contractual indemnities will not apply in situations where a breach by the shipowner of the Warranty Surveyor requirements or of the QA/QC provisions loses the oil company client the right to rely on the cover provided by the CAR policy. In such cases, the knock-for-knock indemnities are more or less useless, since the owner cannot know in advance of an accident, and analysis of the cause, whether or not he can rely on his contractual indemnities to protect him against exposures that are generally excluded from P&I cover as liabilities in respect of contract works. Whilst, of course, owners should always strive to operate their ships properly and in accordance with the requirements of the particular project, it is not realistic to expect shipowners to bear what can be excessively high exposures, especially since the owner's overall benefit from the project is way below that which can be expected by the oil company field operator.

Overall, in any offshore project, it makes sense when considering the level of risk that the parties can reasonably expect to bear to look at the entire operation and to consider where the major exposures, whether insured or not, can fall most appropriately and cost-effectively, and then to draft the contract to reflect this. Unfortunately, this is a counsel of perfection, and there are several factors that militate against it, among them the desire of some clients for their marine subcontractors to "have some skin in the game", a feeling that parties should not expect to be indemnified if they are guilty of really heinous conduct, a lack of clarity on the part of one or both parties about where their bottom line actually lies, and sometimes, a failure to obtain or review the full contract terms in sufficient time to allow for amendment. In one recent case, a member was providing a tug and barge for shipment of a module to a big construction project off West Africa. The day before the charterparty was to be signed, and two days before the shipment was due to take place, the member was sent over 200 pages of additional contractual terms to be incorporated in the charterparty, as the charterer was obliged under the terms of his head contract with the oil company client to ensure that certain terms from the head contract were included in all subcontracts. The 'new' terms included the full liability and indemnity provisions from the head contract, a contract covering a multi-million dollar EPIC project, which had doubtless been negotiated over many months and pored over by numerous corporate lawyers, but which the hapless tugowner was given less than 24 hours to agree, despite the fact that the head contract terms were to take precedence over the terms of the charterparty.

In my opinion, such situations are not helpful for the owner who is at the end of the charterparty chain, nor for the charterer or the ultimate oil company client. It is practically impossible for any owner to accurately assess his exposure in these circumstances or to purchase insurance for the liabilities which he takes on. The charterer may have complied with the terms of the head contract, but the outcome is a liability and indemnity matrix that is highly unclear, that will certainly be subject to expensive and protracted litigation in the aftermath of an accident and that may leave the party ultimately "holding the baby" without insurance. It is far preferable for the parties to negotiate clear and unambiguous contracts under which the risks that they take on are well defined, appropriate and insurable. The club is always available to help members in assessing whether their contract terms are drafted to properly protect the member's position and to advise whether the risks assumed by the member under contract are appropriate for the level and type of insurance that the club can provide.

DEALING WITH RISK IN OFFSHORE DRILLING

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Demand for accessible and secure reserves of oil and gas will continue to present the industry and its insurers with technical and environmental challenges of increasing complexity against a background of intense political and public scrutiny.

INTRODUCTION

The blowout, fire and sinking of the *Deepwater Horizon* in April 2010, with the tragic loss of 11 lives, together with a major pollution incident, put the issue of risk in offshore drilling operations into stark focus. Nevertheless, the demand for accessible and secure reserves of oil and gas will continue to present the industry and its insurers with technical and environmental challenges of increasing complexity against a background of intense political and public scrutiny. As with previous incidents, there will be lessons to be learnt, and the reassessment of risk, together with probable tightening of regulatory controls, will drive changes in technology and operating procedures.

DEVELOPMENT OF OFFSHORE DRILLING AND PRODUCTION

In the late 19th century, wells were drilled from piers extending out from the shore or from platforms piled into shallow water (for example, California, Louisiana, Lake Maracaibo, Baku).

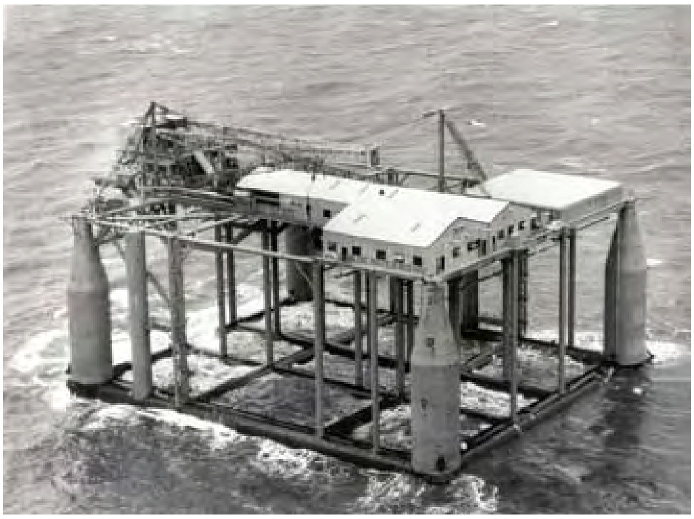
Summerland Beach, California (Oil & Gas Journal)

The Kerr McGee well 'Ship Shoal No. 32', off the Louisiana coast, is heralded as the foundation of the modern offshore drilling industry. The well was drilled in 1947 from a platform off the Louisiana coast, using a converted naval barge as a drilling tender.

As drilling moved into deeper water, jack-up and submersible drilling units were developed. The first semi-submersible drilling unit (actually a submersible operating in floating mode instead of standing on the sea bed) appeared in 1961.

Ship Shoal No. 32, Gulf of Mexico (Oil & Gas Journal)

The development of jack-up and semi-submersible drilling units continued, and drillships were first introduced in the late 1950s. Some modern jack-up drilling units can operate in water depths in excess of 150 metres, while advanced semi-submersibles and drillships now have the ability to operate in water depths of greater than 3,000 metres.



Blue Water Rig No. 1 (Friede & Goldman Ltd.)

Semi-submersibles and drillships can be moored or dynamically positioned (DP). Those operating in extreme water depths (of more than 1,000 metres) are generally DP, although units have been moored successfully in water depths of greater than 2,500 metres (for example, Transocean *Deepwater Nautilus*).

Jack-up Drilling Unit (ENSCO)

Semi-submersible Drilling Unit (Noble)

In just over 60 years, about the same length of time since the development of commercial jet aircraft, the offshore drilling industry has built up the capability to drill in locations ranging from coastal shallows, swamps, rivers and lakes to pack ice, deep water and exposed locations subject to extreme weather conditions.

Whilst the basic processes of offshore drilling, well construction and completion have remained fundamentally consistent over this time, the technology has developed to a high degree of complexity and sophistication. Modern data acquisition and interpretation techniques take much of the guesswork out of the location of potential sources of oil and gas. There is still, however, no substitute for drilling, either to prove the existence of a reservoir or to develop it. Today's high-capacity drilling units, coupled with developments in drilling fluids, directional drilling, well logging and completions technology, enable the discovery and development of complex reservoirs in deep water and hostile environments.

RISKS INHERENT IN OFFSHORE DRILLING AND PRODUCTION

Just as the aviation industry has had its tragic setbacks, such as the loss of the early De Havilland Comet airliners due to fatigue failure of the fuselage, the offshore industry has suffered a number of significant accidents with loss of life and equipment. In December 1965, the jack-up drilling unit *Sea Gem*, which had made the first commercial gas discovery in the North Sea, collapsed and sank with the loss of 13 lives. In 1980, the semi-submersible drilling unit *Alexander L. Kielland* broke up in storm weather and capsized with the loss of 123 lives. In 1982, the semi-submersible drilling unit *Ocean Ranger* foundered in severe weather off Newfoundland with the loss of the entire crew of 84. In 1988, the ignition of leaking gas during maintenance work caused the total loss of the *Piper Alpha* platform in the North Sea, with the loss of 167 lives.

Drillship (BP)

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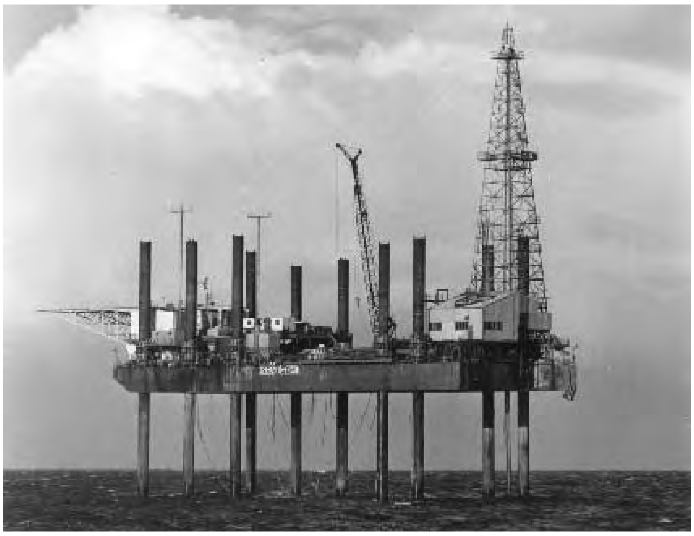

Sea Gem (Dukes Wood Oil Museum)

These and other major offshore incidents have had a profound effect on the perception and management of risk in the offshore industry:

- The techniques of jack-up leg design, in particular, the analysis of the interaction between the legs and supporting sea bed soils and of the hydrodynamic loads imposed by waves and currents, have developed considerably, with significantly greater capability in dynamic modelling, structural design and geotechnical prediction.
- Structural design and fatigue analysis of semi-submersible drilling and production units has become more precise, together with the techniques for accurate determination of environmental loading on structures.
- Critical systems, such as ballast control, fire and gas detection, emergency shut-down and process control systems are generally subjected to risk-based design and operability analysis.

The primary risks associated with offshore drilling and production include:

- loss of watertight integrity and stability of unit
- structural failure of unit
- loss of containment of oil and gas on unit
- station-keeping failure (mooring or DP)
- loss of well integrity (blowout)

RISK ASSESSMENT AND INTEGRITY MANAGEMENT

The UK offshore industry took the lead in moving from prescriptive 'box ticking' application of rules and regulations towards a system whereby it can be demonstrated that asset integrity has been determined from risk assessment; that procedures and processes are established to maintain asset integrity, compliance with applicable laws, codes and standards; and that systems are established to monitor and control operational risks.

Regulatory agencies such as the UK Health and Safety Executive (HSE) and the National Offshore Petroleum Safety Authority (NOPSA) in Australia, classification societies such as Lloyd's Register, Det Norske Veritas and the American Bureau of Shipping, and standards bodies such as the American Petroleum Institute (API) and NORSOK (developed by the Norwegian petroleum industry) have progressively adopted risk-based assessment of the design and operation of offshore units, equipment and systems.

Life-cycle integrity management of offshore units involves activities undertaken at each stage of the unit's life cycle, from design, through construction, commissioning, operation and decommissioning, to ensure that risk is identified and analysed, and that processes and procedures are established for operation, inspection, repair and maintenance of the unit. Life-cycle integrity management integrates the design, functionality, personnel competency, operation, maintenance and repair of the unit and ensures compliance with codes, standards and legislation. Design appraisal of offshore units can be based on an evaluation of performance standards for the unit, based on risk assessment of structure and safety-critical systems. Inspections and testing during construction and commissioning ensure compliance with specification and provide a baseline for risk and reliability-driven inspection and maintenance systems during the operational phase, which are integral to optimised life-cycle integrity management.

The drive to improve reliability and minimise downtime, thereby reducing operating costs, has led to the implementation of reliability-centred maintenance (RCM), linked to risk-based inspection (RBI) schedules. RCM is a process to establish the safe minimum levels of maintenance, based on analysis of failure mode, effect and criticality (FMECA) of structure, systems and equipment. The focus of RCM is to preserve the integrity and functionality of the unit and its systems by developing maintenance schedules that provide an acceptable level of operability within the bounds of an acceptable level of risk. RBI assigns inspection priorities and inspection intervals on the basis of risk analysis, considering the probability and consequences of failure, rather than on a simple time-based schedule that gives equal priority to all, regardless of criticality. Both RBI and RCM follow the principle of ALARP (as low as reasonably practicable) when focusing on risks associated with critical systems to determine priorities for inspection and maintenance. RBI and RCM schemes depend to a great extent on the quality of inspection and maintenance activities, the competence of personnel and adequacy of the information database (structural details, equipment inventory, inspection records, performance data, etc.) that will underpin the system. Additionally, qualitative risk assessment, reliability analysis and FMECA data all contribute to the risk/reliability model that will determine the balance between risk of downtime and inspection effort (and cost). Therefore, the primary elements of a risk-based integrity management scheme are:

- a comprehensive design, construction portfolio
- failure mode analysis (FMECA), reliability analysis, criticality analysis, HAZOP, etc
- ranking of safety-critical equipment and systems
- risk-weighted inspection and maintenance scheme
- comprehensive fault identification, recording and analysis system
- competency and training of operating personnel

Progressive feedback from actual inspection and maintenance activity will refine the risk/reliability model, enabling continuous optimisation of the scheme.

MANAGEMENT OF WELL INTEGRITY AND CONTROL OF BLOWOUT RISK

Well integrity management and well control are prime examples of the application of risk analysis to critical aspects of design and application. Risk analysis is being progressively used in the offshore industry during the planning of wells and the identification of potential hazards. An important part of the analysis is to determine the equipment and procedures necessary to manage both expected and unexpected wellbore conditions and prevent uncontrolled release of wellbore fluids.

In the early days of oilfield operations, there was no way to control the well if the underground pressures encountered in the wellbore during drilling were to suddenly exceed the hydrostatic head of the drilling mud. When the oil or gas reservoir was encountered, wells were just allowed to 'blowout' until the pressure was reduced sufficiently to allow a valve to be fitted to the wellhead.

Well control is the means whereby drilling and production operations can safely proceed without uncontrolled flow of formation fluids from the wellbore (blowout).

Primary well control is achieved by the use of drilling fluid (mud) density to provide sufficient hydrostatic pressure to prevent the influx of formation fluids into the wellbore. Drilling mud is pumped down the drill pipe to the drill bit, where it is ejected via nozzles that assist the cutting action of the bit. The returning mud flow up the annulus carries the rock fragments cut by the drill bit (cuttings). These are removed at the surface and the drilling mud is recirculated down the well. The density of the drilling mud has to be such that the hydrostatic head at the bottom of the well balances or slightly exceeds the pore pressure of the formation. The circulating pressure is generally higher than the hydrostatic head, due to dynamic effects and weight of the cuttings. The circulating pressure and flow rate are calculated to optimise bit hydraulics and cuttings transport. The pore pressure is the pressure of fluids that occupy the interstitial spaces between the particles of the rock. As the drill bit penetrates the rock, changes in pore pressure may occur as the bit penetrates a different formation – for example, from a shale to a sandstone. If the density of the drilling mud is too great, the rate of penetration (ROP) will be slowed down and there will be a risk of causing formation damage by mud infiltration into the formation or even exceeding the formation fracture pressure. This can lead to loss of drilling mud into the formation (lost circulation). If the density of the drilling mud is less than the pore pressure, ROP will be high, but there will be a risk of influx of formation fluid to the wellbore (known as a 'kick'). Sometimes, where the lithology and formation tops are known, drilling may proceed with a drilling mud density of less than the formation pore pressure. This 'underbalanced drilling' allows for high ROP and 'drilling for kicks', where an influx indicates that a formation target has been reached.

Primary well control procedures require the close monitoring of drilling fluid circulation volume, ROP and the composition of the fluid and solid returns that are circulated up the wellbore, particularly if drilling underbalanced. Any gain in circulating volume indicates an influx from the wellbore. There may also be an increase in the level of gas in the drilling mud, which can be detected by mud-logging instruments. At intervals, drilling is suspended and checks made for flow in the annulus and, periodically, the mud is circulated 'bottoms up' to check for entrained wellbore fluids.

BLOWOUTS

Blowouts are caused by a loss of hydrostatic balance in the well, due to an influx of formation fluid (oil, gas, water) or the loss of drilling mud into a lost circulation zone (thief zone) causing such a reduction in hydrostatic head that fluids are able to enter from another zone. If the drilling mud density is close to the pore pressure, a kick can occur when circulation stops, e.g. to connect more drill pipe or to check for flow. A kick can lead very quickly to a blowout, particularly if there is a high concentration of gas in the influx. Gas expands very rapidly as it travels up the annulus and displaces the drilling mud. The resultant loss of hydrostatic head allows more gas to enter the annulus and, if unchecked, a blowout occurs.

Blowouts can be caused during tripping operations to change the drill bit or bottom hole assembly. If the bit is withdrawn from the open hole section too quickly, there is a suction effect (swabbing) that causes formation fluid to be drawn into the wellbore. Because the well is not being circulated at that time, the kick will go undetected until there is a flow of drilling mud at the surface.

___Well integrity management and well control are prime examples of the application of risk analysis to critical aspects of design and application. Risk analysis is being progressively used in the offshore industry during the planning of wells and the identification of potential hazards. An important part of the analysis is to determine the equipment and procedures necessary to manage both expected and unexpected wellbore conditions and prevent uncontrolled release of wellbore fluids.

Spindletop, Beaumont Texas 1901 (John Trost)

In deep water, a blowout could result from the loss of drilling mud in the riser; for example, to avoid collapse of the riser due to mud losses to a thief zone in the well, most deepwater risers have an automatic fill-up valve that allows seawater to flow into the riser. The density of the seawater will generally be lower than that of the drilling mud, so a significant loss of hydrostatic head will occur in the well.

A blowout may occur when the drilling mud is being displaced from the well and riser during abandonment operations, if there is an inadequate seal between the cement and the casing or liner, or a failure of downhole hangers or plugs.

An underground blowout can occur when fluid from a high-pressure zone flows uncontrolled into a lower-pressure zone, usually higher in the wellbore. Casing programmes are designed to eliminate this risk by isolating different formations from each other.

The general method of dealing with a kick is to shut the well in by closing the blowout preventer (BOP) and circulating the kick to the surface by pumping drilling mud into the bit at a controlled rate and pressure, while passing the return flow through a choke, which can exert back pressure to prevent further influx. This procedure can be complicated in deep water, due to friction and hydrostatic effects in the long, small diameter choke line between the subsea choke valve on the BOP and the choke manifold on the drilling unit.

The first ram-type BOP was introduced in 1922. This mechanism allowed the manual closing of a well and quickly became a standard piece of industry equipment. It was installed on the wellhead, and the rams could be closed to seal off the well, allowing full control of the pressure during drilling and production. The original design could withstand pressures of up to 3,000 psi (pounds per square inch), an industry record at that time.

Modern variants of the ram-type BOP remain the industry standard today; many BOPs on modern drilling units are rated at up to 15,000 psi and are deployed in water depths of 3,000 metres (10,000 feet). There are three types of ram BOP in common use:

- pipe rams
- blind/shear rams
- variable bore rams

Pipe rams are designed to close and seal against the drill pipe and have hard nitrile inserts shaped to the profile of the pipe diameter (typically 5 inches). Blind/shear rams are designed to shear drill pipe, tubing or casing, depending on the ram inserts selected, and then close tightly to provide a pressure-tight barrier or, if no pipe is in the BOP, to close and engage to provide the pressure-tight barrier. Variable bore rams have an ‘iris’-type closure (like a camera lens), designed to close and seal against different diameters of drill pipe.

A typical subsea BOP may contain a lower double pipe ram, with inserts sized for the working drill string (typically 5 inch diameter) and an upper double with blind/shear ram and either a 3-inch pipe ram or a variable bore ram. When closing the BOP, it is essential that the drill pipe is ‘spaced out’ in such a way that the shoulder of the tool joint (the screwed connection between joints of drill pipe, which has a larger outside diameter than the main body of the pipe) is just above the uppermost pipe ram for the pipe diameter. In that way, the drill string can 'hang' on the upper pipe ram and the lower pipe rams are then able to close and seal against the body of the pipe. The dimensions of the BOP stack also ensure that, in this configuration, the shear rams will be able to close on pipe and not on a tool joint, which they may not cut cleanly.

With the pipe rams closed, the well can then be circulated via the drill string and the choke valve on the BOP stack below the lower pipe ram.

BOP stack (Cameron)

Most deepwater BOPs are rated at 15,000 psi and have a bore of 18¾ inches. The BOP is connected to the drilling unit by a marine drilling riser. The riser, which is tensioned on the drilling unit, conducts the drilling fluid back to the surface, where it is conditioned prior to being pumped back down the drill pipe to the drill bit. The riser is an important component of the well integrity system, particularly in deep water, as the hydrostatic head of fluid in the riser is part of the primary well control system. When the well is shut in at the BOP, this hydrostatic head disappears and account must be taken of that in the well integrity analysis. At the top of the riser, there is a telescopic joint, which absorbs the vertical motions of the drilling unit. There is also a diverter that can be closed to enable discharge of fluid overboard in the event of a shallow gas kick. Whilst the diverter is normally open during drilling operations, increasing use is being made of 'managed pressure drilling', where the diverter is replaced by a rotating control device (RCD) to enable the entire circulatory system, including the riser, to be closed and pressurised. Managed pressure drilling allows precise control of the wellbore pressure profile and has the potential to allow faster corrective action to deal with pressure variations and avoid formation fluid influx while optimising well hydraulics, bit performance and ROP.

Early subsea BOPs were controlled remotely from the surface by pumping hydraulic fluid directly from a control panel on the drill floor to the individual activators on the BOP. As water depths increased, this method became increasingly impractical, due primarily to the time delay between activating a function at the surface and its execution on the BOP, also due to pressure losses over the length of the control hose and the reduction in pressure differential between the control system and the sea at the depth of the BOP.

Deepwater BOPs are controlled by a multiplex system. Commands are sent electronically to control pods on the Lower Marine Riser Package (LMRP), which use solenoid-activated pilot valves to direct hydraulic fluid to the main actuators. Electrical and hydraulic power is transmitted from the surface via umbilicals and stored at the BOP in batteries and accumulators. Each control pod is capable of activating all the functions on the BOP, so there is complete redundancy and the control software carries out continuous tracking and error checking of the status of the control pods and BOP functions. In the event that the umbilical is disconnected, an acoustic backup system can activate the primary functions on the BOP. Remotely Operated Vehicles (ROVs) intervention can also be applied to some primary BOP functions.

The illustration of a deepwater BOP stack shows the 'blue' and 'yellow' control pods on the LMRP. The LMRP also contains a flexjoint to allow for angular deflection of the riser and an annular BOP, which will typically be rated at 5,000 psi. The lower section contains the wellhead connector, BOP rams and accumulators for storage of the hydraulic control fluid.

FAILURE MODES OF BOPS

BOP stacks have long been regarded as the ultimate defence against blowout, and all drill crews receive training in their use. A subsea BOP is generally tested to its rated pressure while on a test stump on board the drilling unit, usually before being deployed on a well. Once the BOP stack is subsea, testing is usually carried out on a weekly basis or prior to special tasks, such as running casing. Regular testing uses a test plug in the casing hanger or in the casing itself. To avoid casing damage if the test plug leaks, the routine tests are usually limited to about 80% of the rated casing burst pressure.

BOP failures may be due to malfunction or inability to provide full pressure containment. As described above, subsea BOP control systems have several levels of redundancy but are not fail-safe, i.e. the status of the BOP is dependent on a command sent from the surface control panel. The only fail-safe sequence is in the event of an emergency disconnect of the riser and LMRP, where a predetermined sequence is automatically triggered when the emergency disconnect function is activated. The emergency disconnect function will close shear rams, subsea choke and kill valves, and release the riser connector but will be dependent on correct space-out of the drill string to ensure that the shear ram does not attempt to close on a tool joint.

BOP control system failure may occur as a result of a loss of electrical power, flat batteries, software malfunction, loss of hydraulic accumulator pressure, leakage of hydraulic fluid from control pods or pilot valve failure.

Failure of a subsea BOP to contain pressure from the wellbore may be due to a number of factors. First and foremost, the drill pipe should be correctly spaced out and stationary when the pipe rams are closed. The annular preventer will close on various diameters of pipe, including open hole, but is generally rated at 5,000 psi. Whilst the annular will permit the movement of pipe (stripping) in the event that the drill string was off bottom at the time of the kick, the pipe rams will not allow the passage of a tool joint. Stripping of pipe through a pipe ram is usually accomplished by ram-to-ram or ram-to-annular procedure, but the full closing pressure is not applied to the pipe ram when pipe is moving. A severe kick can impose a force to eject the drill pipe from the well, or it may be attempted to close pipe rams without the drill string being correctly hung off. Either way, if the pipe rams are closed with full system pressure on moving pipe, the nitrile seal inserts may be damaged or ripped out, thereby preventing a pressure tight seal. Ram BOPs usually have hydraulically activated wedgelocks to keep them closed. If, for any reason, the wedgelocks fail to close and the hydraulic pressure on the rams bleeds down, the rams will not continue to seal.

The ultimate defence is to close the shear rams, cutting the drill pipe and allowing it to slump. If, however, there is a tool joint in the shear ram, it may not effect a clean cut and subsequent seal. If the kick was sufficiently violent, there may be sand, rocks and other debris inside the BOP, or even a dislodged casing hanger, all of which could prevent the shear rams from closing effectively.

CONCLUSION

The progression of the offshore industry into deeper, remote, hostile and environmentally sensitive areas requires a commensurate understanding, assessment and management of the associated risks. Risk-based asset integrity management schemes and well integrity schemes are progressively replacing adherence to prescriptive rules.

The failure of the *Deepwater Horizon's* BOP sends a stark signal that the offshore oil industry's ultimate defence against the risk of blowout for nearly 90 years is not infallible. A radical reappraisal of the role of BOPs in well control, together with a comprehensive examination of the risks inherent in deepwater offshore drilling, could increase confidence in the integrity management of offshore exploration and production.

LIMITATION OF LIABILITY FOR POLLUTION DAMAGE FOR OFFSHORE VESSELS AND UNITS IN THE NORTH SEA (NORWEGIAN SECTOR)

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The failure of the blowout preventer on the *Deepwater Horizon* caused a massive on-going oil spill in the Gulf of Mexico and the largest pollution incident in US history. This is a pertinent time to ask what would the consequences be for operators of offshore production facilities if a similar incident were to occur in the Norwegian sector of the North Sea? What is the liability exposure for the various interests involved and can that liability be limited?

When considering the potential liability and limitation for offshore vessels and units, it is necessary to first distinguish between pollution damage and other types of damage. In Norway, liability for and limitation of pollution damage is partly regulated by the Petroleum Activities Act 1996 (Petroleum Act) and partly by the Norwegian Maritime Code 1994 (Maritime Code). The focus of this article will be on pollution damage, but with passing reference to the rules on limitation for other types of damage.

The starting point is to identify the source of the pollution and the relevant vessel or unit involved. Consideration must then be given to the applicable statutory liability and limitation regime. As statutory rules generally only regulate third-party liability, consideration will also inevitably need to be given to any applicable contractual scheme as this may well determine where the liability finally rests. However, and whilst undoubtedly important, an overview of the relevant contractual schemes is beyond the scope of this article.

POLLUTION DAMAGE WITHIN THE SCOPE OF THE PETROLEUM ACT

Pursuant to the Petroleum Act, a licensee (being the holder of a licence to carry out petroleum activities at the relevant oil field) is strictly liable for pollution damage. Pollution damage covers damage or loss caused by pollution as a consequence of the discharge of petroleum from a facility, including wells, together with the costs of any reasonable measures taken to avert or limit such damage. Facilities in this respect are defined as installations, plants and other equipment for petroleum activities, but do not include supply and support vessels or ships that transport petroleum in bulk other than when such vessels are loading from the facility. Ships used for drilling and for storage in conjunction with production are also regarded as part of the facility, as are pipelines too.

Provided that the pollution damage falls within the scope of the Petroleum Act, the licensee has, save for certain *force majeure* events such as natural disasters or an act of war, no right to limit their liability.

Claims against a licensee for pollution damage may only be pursued in accordance with the regime laid down by the Petroleum Act. Liability for such claims is channelled to the licensee and cannot be brought against anyone who by agreement with the licensee or his contractor(s) has performed tasks or work in connection with the petroleum activities. This channelling provision protects most parties involved in the relevant petroleum activity but will, for example, not include ships that transport petroleum (apart from when they are loading), or ships or units that are involved in petroleum activities other than where the pollution damage occurred.

The licensee is barred from seeking recourse against any party exempted from liability by the channelling provision, save where the party in question has acted wilfully or is grossly negligent. In the latter case, the licensee may seek recourse, but for such recourse claims, the relevant party may invoke the right to limit liability under the Maritime Code.

POLLUTION DAMAGE OUTSIDE THE SCOPE OF THE PETROLEUM ACT

Outside the scope of the Petroleum Act, two different liability and limitation regimes apply with respect to pollution damage. Firstly, Chapter 10 of the Maritime Code incorporates the International Convention on Civil Liability for Oil Pollution Damage 1992 (CLC 92). Secondly, the Convention on Limitation of Liability for Maritime Claims of 1976 (as amended by the 1996 Protocol) is incorporated in the Maritime Code Chapter 9 (LLMC 1976).

The starting point under Chapter 10 of the Maritime Code is that owners of ships, drilling rigs and other mobile installations are strictly liable for damage or loss resulting from pollution caused by oil escaping or being discharged from the ship or installation, including costs for any preventive measures. However, outside the principle of strict liability, the regulation of liability and limitation will depend on the type of oil, the type of ship or unit involved, and where the loss or damage occurred.

If the pollution is caused by persistent oil released or discharged from a ship transporting cargo in bulk and the resulting pollution causes damage in Norway, the rules in CLC 92 are applicable. The standard CLC 92 rules on limitation of liability, channelling of liability and mandatory insurance apply, and where applicable, the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage of 1992 (1992 Fund) may also be called upon.

The failure of the blowout preventer on the *Deepwater Horizon* caused a massive on-going oil spill in the Gulf of Mexico and the largest pollution incident in US history. This is a pertinent time to ask what would the consequences be for operators of offshore production facilities if a similar incident were to occur in the Norwegian sector of the North Sea?

However, if the claim is one that also falls within the scope of the Petroleum Act, then the limitation provisions in CLC 92 cannot be used by a licensee or an operator for claims relating to such pollution damage, and no recourse claim may be made against owners of ships, drilling rigs and other mobile installations provided that they have not acted wilfully or been grossly negligent.

SPECIFIC LIMITATION RULES FOR OFFSHORE UNITS UNDER LLMC 1976 RELATING TO CLAIMS THAT FALL OUTSIDE THE SCOPE OF THE PETROLEUM ACT AND CLC 92

If persistent oil is released or discharged from a ship, drilling platform or other similar mobile installation not transporting oil as bulk cargo (i.e. outside the scope of CLC 92), then the provisions of LLMC 1976 will apply. This Convention is also applicable where pollution of non-persistent oil occurs. Under LLMC 1976, there are no channelling provisions, mandatory insurance or, if relevant, excess cover under the 1992 Fund.

Liability for wreck removal and other clean-up costs arising out of a maritime casualty is generally subject to limitation under LLMC 1976. Under the 1996 Protocol, countries may reserve the right to exclude liability for wreck removal and clean-up costs from the scope of the 1996 Protocol, which a number of states have done. Norway adopted this reservation in 2002 and, in 2006, more than doubled the limitation amount which could be claimed under the 1996 Protocol for such costs. The implementation of the higher limits was mainly driven by the Norwegian government's wish to have all clean-up costs covered by shipowners and their insurers. Depending on the relevant damage, the shipowner may have to establish two funds: one for ordinary LLMC 1976 claims and a separate fund for wreck removal and clean-up related costs.

After the *Server* casualty in January 2007, the limits for wreck removal and clean-up costs were again increased to more than double the existing limits and currently are as follows (the figures do not show limits for personal injury claims):

Gross tonnage	LLMC 1976 (SDR* million)	1996 Protocol (SDR million)	Clean-up fund limits (SDR million)
1,000	0.25	1	2
6,000	1.1	2.6	24
20,000	3.4	8.2	54
70,000	10.1	24.2	104

* SDR: special drawing rights

SPECIAL LIMITATION AMOUNTS FOR DRILLING PLATFORMS AND SIMILAR MOBILE CONSTRUCTIONS

According to article 15 no. 5 of LLMC 1976, the Convention does not apply to *"floating platforms constructed for the purpose of exploring or exploiting the natural resources of the seabed or the subsoil thereof"*. As a result, in 1979, special rules were incorporated into the Maritime Code Chapter 21, Drilling Platforms and Similar Mobile Constructions, Section 507. Insofar as the relevant unit is a drilling platform or similar mobile construction and *"not regarded as [a] ship[s] and [is] intended for use in… exploitation… of subsea natural resources"*, the Maritime Code Chapter 9 applies but with the specific limits of SDR36m for personal injury, and SDR60m for other claims and clean-up costs, respectively.

SUMMARY

It is clear from this brief summary that were an event like the *Deepwater Horizon* to occur in the Norwegian sector of the North Sea, then a web of legislation and conventions will come into play to determine where the liability ultimately falls, and how far licensees and operators of offshore production facilities and vessels can limit their liability. Whether the ultimate payer is the deep pocket of an oil company or an international fund or an insurer, the route by which such liability is imposed is often a complex one.

HARD HATS AND FLIP-FLOPS – SOME PERSONAL VIEWS ON OIL INDUSTRY SAFETY

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Much of my offshore career was dedicated to the introduction of ROVs to displace the North Sea diver – diving being one of the most hazardous jobs of that era. But despite our success, a respected colleague was killed by the cure, crushed as he reached out to steady a two-ton ROV swinging on its lift line.

On that late summer day in 1980, we received an excellent pre-flight safety briefing in the departure area before, immersion suits donned, we boarded the helicopter and charged out into the South Atlantic. When we touched down onto the helideck of the offshore production platform, we were quickly moved away from the noise of the rotor blades into the reception cabin. Again, another first-class safety briefing, but this time, we were issued with H_2S masks – the production here contained a high level of the invisible killer. We exited the room and outside on the walkway was a man painting the wall. In his left hand a one-gallon paint can, in his right a brush. And he was at first glance properly equipped, with overalls and hard hat, but on his feet were flip-flops. If he had dropped the can, it could have removed his toes.

Several thousand miles north and eight years later on July 6 1988, 167 men died in the explosion and inferno that devoured the *Piper Alpha* offshore platform, because of what is nowadays called 'human error'. A tube to a pressure safety valve on a backup condensate pump had been removed for service and a temporary closure plate fitted to the pipe end. Later in the evening during the next work shift, the primary condensate pump failed. None of those present were aware that a vital part of the machine had been removed and decided to start the backup pump. Gas escaped from the hole left by the valve, ignited and exploded. The automatic deluge system was not activated because it had been turned off. Amongst other findings, it was concluded that if the 'permit to work' system had been implemented properly, the initial gas leak would never have occurred.

I had spent some 12 years prior to this event working in the various aspects of the underwater contracting business, and although I was not a full-time offshore worker, I had a number of near misses: the helicopter that crashed a few feet from me on the Brent Spar helideck, the ship's mooring cable that parted a couple of feet above me as I was repairing a remotely operated vehicle (ROV) below it, showering me with fragments – if I had been standing not kneeling, it would have removed my head. Both were incidents that should not have occurred – but they did. Then on one occasion, pressure of work meant that I missed my flight home on the company plane – it crashed!

Much of my offshore career was dedicated to the introduction of ROVs to displace the North Sea diver – diving being one of the most hazardous jobs of that era. But despite our success, a respected colleague was killed by the cure, crushed as he reached out to steady a two-ton ROV swinging on its lift line. We all make mistakes, but mostly we survive our mistakes and learn from them.

The fact remains that the offshore oil and gas industry is potentially very dangerous, and in response to such events as *Piper Alpha*, it has developed a culture of safety that is now deeply ingrained – but perhaps too much so. Are we now at the point that everyone expects their workplace to be completely safe and so stops thinking for themselves?

A new industry has developed. An army of people fix hazard signs on trivia, the number of lapses of Health and Safety at work regulations reported by an oil-industry worker becomes a plus factor in their annual reviews and industry meetings begin with a 'safety moment'. At my own firm, a visiting oil company man returning to the meeting after a 'comfort break' interrupted the proceedings to put on record a safety lapse – the lavatory seat was loose! In other oil company offices, signs instruct staff on how to walk up and down stairs safely.

Perhaps all this money could be better spent. In my view, the box ticking and patronising safety sign culture has served to remove our reliance on basic common sense, often with disastrous results. Addressing minor risks is important, but addressing the potential of a catastrophic disaster, and recovering from it, much more so.

So what is the relevance of all this to the *Deepwater Horizon* catastrophe? Over the past five years alone, more than 18,000 wells were drilled offshore, of which some 2,500 were in deep water (greater than 500 metres). And nothing remotely like this happened – the offshore oil and gas industry has in the last 22 years achieved an excellent safety record. As a result of some individual past disasters such as *Piper Alpha*, it has become safety obsessed, and both hardware and procedures are based on layers of fail-safe systems. So it is very difficult to understand why the *Deepwater Horizon* tragedy ever occurred.

At present, there is much speculation. But the answers to what went wrong, why 11 men died and why millions of barrels of oil were dumped into the Gulf of Mexico will have to wait the analysis following the recovery of the blowout preventer and the full investigation. All of us know that the BOP is designed to be fail-safe, but it seemingly did not, and more fundamentally, as an industry, we were unprepared and totally lacking in appropriate hardware and procedures to quickly stop the flow.

Deepwater Horizon will have a major impact on the industry in the years ahead. We must understand what went wrong and learn from it. The industry will benefit greatly from that knowledge.

But perhaps we need a return to the thinking of the late 1970s, when Statoil was planning its first deepwater pipeline. This was designed and built to the highest safety standards of the day, but just in case the worst happened, a major deepwater pipeline repair system was also designed and tested, and then strategically positioned in a port to wait for the day it might be needed. It never was.

For most people, their only contact with the oil industry is filling their car. Next time, look at the safety notices – the pumps at my local filling station each have 10. Upon asking friends and colleagues, I have been unable to find anyone who has ever read any of them. So why are they there? To enhance safety or to act as a foil against predatory lawyers in the event that the worst happens?

When was the last time you actually listened to the pre-flight safety briefing, or looked at the safety card, or checked that the life jacket is under your seat, or counted the number of rows of seatbacks you will have to pass in the dark to fight your way to the emergency exit of the crashed plane?

As the increasing number of safety signs and suchlike relegates them to the status of visual background clutter, I believe that our lives become potentially more exposed to major disasters. The little routine things are important, but while the 'safety industry' ticks its boxes, are we ignoring the major hazards? Is a rebalancing of individual and corporate attitudes to safety required?

And what of the 'hard hats and flip-flops' offshore platform? Some months after my visit, it was destroyed in a massive explosion and fire.

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NORTH SEA DECOMMISSIONING CONTRACTING FOR THE KNOWN AND UNKNOWN UNKNOWNS

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Only about 7% of all installations in the UK sector of the North Sea have been decommissioned[1]. Smaller projects have been executed safely, on time and within budget by a small but experienced group of contractors, and onshore recycling has been carried out in accordance with environmental and waste disposal regulations to the satisfaction of the relevant authorities. However, larger, high-profile projects have been tougher than anticipated, involving serious cost increases, delays, losses and liabilities for the contractors.

Although costs have increased dramatically in recent years for a variety of reasons, this is only part of the picture. Initial experience is that decommissioning projects are difficult to manage because of their inherent uncertainties. In particular, the availability and accuracy of 'as built' information about installations is, at best, limited. Work methods have to be revised. Platforms have also turned out to be unsafe to work on, with the integrity of parts not being as strong as anticipated. Offshore crew may fail to achieve anticipated productivity. Delays can occur in the supply chain. Weather downtime may be greater than planned. Subcontractors may fail to perform. There may be limited availability of heavy lift operators and recycling yards.

Also, platforms were generally not designed for removal, and each installation brings its own challenge. Topsides and jackets involve different issues. The logistics and procedures for removal of topsides require consideration of the integrity of modules, lifting aids, cleaning, waste disposal, cutting methods, salvage and offshore preparatory work. Jacket removal entails cutting, lifting and handling technologies, which heavily depend on the integrity of the jacket. This can be more complex for larger structures, where the height rather than weight may be a restricting factor. Flotation, cutting methods, cutting piles below the seabed and transportation all present challenges.

Numerous processes are involved: plugging and abandonment of wells, cleaning and hook down, removal and/or recycling of platforms, pipelines and contaminants in the surrounding area. Managing the project requires co-ordination of a number of departments and disciplines, including Drilling, Operations, Construction, Subsea, HSE (health and safety at work regulations), Planning, Cost Reporting, Document Control, Procurement, etc. Inadequate project organisation can easily extend the project and increase costs. In particular, concerns have been expressed that the operators' rules, regulations and permit-to-work systems, whilst apt for offshore operations on a live installation or during construction, are not suited to a decommissioning project.

As a result, projects have often been delayed and disrupted. Unfortunately, for some of the contractors involved, lump-sum contracts based on EPIC-type terms (engineer, procure, install and commission) have not been entirely successful in apportioning the risks that have arisen. Although there have been demands for a standard decommissioning contract, LOGIC[2] has not so far been able to produce one. Indeed, there are obvious difficulties in doing so, and a number of issues need to be addressed.

First and foremost, decommissioning is not the reverse of installation, and there is no schedule incentive such as a 'first oil date' to keep all parties focused. An operator's incentive in a removal project is more likely to be based upon the cost, risk and safety implications.

Further, there is no standardised offshore installation. There are a variety of decommissioning strategies involving reverse engineering, removal of small pieces, and single lifts. The various combinations of pricing and means by which the contractor is to be incentivised in return for sharing the risk of known and unknown unknowns require different approaches. If the contract is on a lump-sum basis, special attention must be paid to terms dealing with the accuracy of tender information, revisions due to delay, unexpected work and stage payments. If the contract is on a measured work basis, thought will have to be given to establishing the applicable norms. If on a reimbursable basis, or time and materials plus mark-up basis, the manner in which the tariffs are to be calculated to reflect risk and reward must be carefully considered.

1 The following have been decommissioned in the UK sector: three installations with large concrete substructures, one with large steel jacket, 15 other steel jackets, seven floating production systems, two subsea production systems, 10 other facilities (loading buoys, flares etc), 16 pipeline programmes. Major decommissioned installations include *West Sole, Brent Spar, Maureen, Hutton TLP, Brent Flare & Anchors, NW Hutton, Frigg MCP-01, Kittiwake Loading Buoy.* Over 400 installations remain, including eight installations with large concrete substructures, 31 with large steel jackets, 214 other steel jackets, 278 subsea production systems, 21 floating production systems, 3,300 pipelines – around 25,000km, <5,000 wells, <200 cuttings piles.

2 The subsidiary of Oil and Gas UK which develops and issues standard contracts for use in the UK oil and gas industry.

“There are known knowns. These are things we know that we know. There are known unknowns. That is to say, there are things that we now know we don’t know. But there are also unknown unknowns. These are things we do not know we don’t know.” (Donald Rumsfeld)

Removal of a jacket

Defining the work scope will also be important. Is there to be a detailed specification for defined tasks, or a general obligation to remove in accordance with the operator’s abandonment programme? Who is to be responsible for each stage of the engineering, provision of personnel, craft and equipment, decommissioning, removal, disposal or abandonment? Will the operator’s representatives supervise and be able to require changes to the work scope? What duties will the operator have to assist and co-operate in the provision of personnel and equipment?

If information and drawings turn out to be inaccurate, how is this to be dealt with? Will warranties be given by the operator in respect of the condition of the installation and the information or drawings provided? Or will the contractor have a duty to inform itself?

Who will be responsible for obtaining all licences, approvals, authorisations or permits for disposal from the numerous authorities involved?

Crucially, how are the risks of the known and unknown unknowns to be dealt with? Who will bear the additional time and cost consequences, and how are these to be determined? Is there an appropriate mechanism for price adjustment in such circumstances, and if the operator delays the project?

The usual knock-for-knock[3] indemnities in relation to property, loss of life, personal injury to personnel and third parties may also need to be adapted. The additional costs of putting something right on the installation may well be contested by the operator. Nearby facilities or pipelines may be owned by different parties and there could be large consequential losses, which the contractor will not want to bear.

Such indemnities will need to dovetail with provisions for insuring these and other risks. There is no standard insurance for decommissioning and removal operations, and a contractor may be presented with a modified CAR (Construction All Risks) cover for physical damage, third-party liabilities, control of well and consequential loss. Wreck removal obligations for dropped objects and contractors’ vessels may also require consideration in light of the contractors’ P&I cover, which may only respond if the wreck is a hazard to navigation or a wreck removal order is issued.

There is also an appreciable risk of residual liabilities in perpetuity arising from abandonment, such as environmental pollution from wellhead seepage, seabed remains, pipelines and onshore disposal of hazardous waste. A contractor will be looking to negotiate adequate exclusions or limitations for direct and indirect consequential losses, or to arrange insurance cover for residual liability risk, environmental pollution risks, loss of contract earnings and/or standby, and political risks.

Just as building the first offshore oil installations opened up new areas of law in the 1970s, the need to remove the older installations in an environmentally acceptable manner is opening up a new industry and a new field of law that will require innovative contracting solutions. Risks unique to each installation need to be fully explored and allocated. Contracting for the known and unknown unknowns will be a challenge. But there is one known. Contracts that do not reflect the realities of a particular project will lead to expensive disputes.

3 In the offshore industry, risk is commonly allocated by means of knock-for-knock contracts. These are contracts under which the parties take responsibility and indemnify one another for loss of, or damage to their own property, or injury or death of their personnel, regardless of fault.

NORTH SEA DECOMMISSIONING DEMANDS A STANDARD CONTRACT

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There are more than 450 platforms, more than 13,000km of pipeline and 900 wells in the North Sea.

The lack of a standard legal contract to cover the decommissioning and removal of North Sea offshore oil and gas installations needs to be urgently addressed. The first major decommissioning was done under a modified installation contract, leading to losses and liabilities for the contractor. Just as building the first offshore oil installations opened up new areas of law 30 years ago, today the need to remove the older installations in an environmentally acceptable manner is opening up a new industry and a new field of law.

There are more than 450 platforms, more than 13,000km of pipeline and 900 wells in the North Sea, of which more than 2,000km of pipeline and more than 150 platform installations are in the Dutch sector. Over the next decade, the speed at which these will become obsolete will increase, and decommissioning work will accelerate.

Licence holders and operators of North Sea offshore energy installations are going to have to spend around €50bn decommissioning and removing all of the obsolete infrastructure in the North Sea. There are a number of installations that will have to be decommissioned and removed in the next two or three years. Work on the second biggest project is under way in the Norwegian Ekofisk field. Although there are attempts currently being made to define a standard contract, by LOGIC[1] and other organisations, as yet there is nothing proven in practice.

The situation is complicated because of different legal regimes. In the UK sector, there is a carry back liability, which means that removal and environmental liability costs can be shared back along the chain of users, owners and licence holders from the time of the original installation until its decommissioning. In the Norwegian sector, there is a slightly different legal regime.

The last licence holder for the block is responsible for the removal of installations in the Dutch sector. Any offshore oil installation in the Dutch sector is considered a mining installation under Dutch law, and the Dutch Mining Act applies. It states that a mining installation that is no longer in service needs to be removed. But the Act does not specify how or when this should be done. The Mining Decree gives some guidelines. Article 60 states that the decommissioning and removal of the installations will have to be done in accordance with a removal plan drafted by the operator.

In the Dutch sector, the last operator and licence holder will try to contract a decommissioning firm to remove the installations from the field. They will also try to impose all of the risks upon the contractor. So far, the demolitions attempted have been done under modified offshore installation contracts, with poor results for the contractors. For future work, a clearer contract with better risk-sharing is required.

It could be argued that the legal status of the structure of an offshore installation changes when the contractor cuts off a lump of structure and lifts it out of the sea, and the obsolete structure on the crane ceases to be a structure and becomes waste. It then has to be imported legally as waste and disposed of under the waste disposal regulations. Degasification of facilities, removal of oil and making wells safe by permanent plugging and abandonment will all form part of the decommissioning process. Many of these structures contain asbestos and certainly all of them contain dangerous liquids, toxic PCBs in wiring and other hazardous material. But given their age and the many modifications done, not all of this material may be fully documented, with the result that there may be surprises during the decommissioning. The contractor will take full responsibility for the health and safety of workers and the disposal of this waste, but needs a clear legal regime to share the associated risks.

1 The subsidiary of Oil and Gas UK, which develops and issues standard contracts for use in the UK oil and gas industry.

LONDON MARKET: OFFSHORE WIND OF CHANGE

Offshore wind energy is going to be big business – and so too the opportunities for insurers. But not all of it will be plain sailing for underwriters.

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The North Sea is about to experience a bonanza reminiscent of the oil rush of the 1970s. Europe's offshore wind energy market is forecast to be worth £75bn over the next decade, with the lion's share going to the waters off the UK. The weather may be miserable, but it sure can blow.

The planned London Array is the most dramatic manifestation of the country's commitment to harness one of its biggest natural assets. A project that defies the imagination, it will become by far the world's largest offshore wind farm. Situated 12 miles off the Kent and Essex coastline, it will cover 80 square miles and is expected to supply 7% of the country's energy needs by 2015, when the second stage is complete.

TECHNICAL AND COMMERCIAL CHALLENGES

Think of 341 turbines towering 100 metres above sea level and linked by up to 700 different undersea cables, and then try to calculate the logistical complications of construction, maintenance and converting all this technology into usable electricity intended to power 750,000 homes. There is plenty of potential business here for insurance underwriters.

The Array is just one part of the jigsaw, although admittedly an exceptional one. Over the past 10 years, the ocean off the British coastline has been divided into plots chosen for their climatic conditions. Despite the enormous technical and commercial challenges, the franchises have proved popular with potential bidders. Just as Aberdeen became an oil town, some areas in the North-east are expected to enter a new era of prosperity on the back of wind power.

The last government's tax and carbon credit subsidies enticed would-be investors weary of the fluctuating commodity markets. The coalition government has continued to support the green approach, with the Department of Energy and Climate Change announcing £10m of grants for the offshore wind industry in July.

The London insurance market has been quick to rise to the challenge, reflecting its level of specialist expertise and willingness to take on new risks. The emergence of any extra segment of business is bound to excite interest, but especially a high-profile one such as this. Insurers, like everyone else, want to be seen to be green. As a result of this popularity, there are more insurers trying to get into the market than there are underwriting teams that truly understand the associated risks.

The firms involved in construction generally work to the highest standards. For example, a consortium between Eon, Dong Energy and Masdar has footed the £2bn investment required to bring to life the London Array. And there have been complex technical discussions involving certification bodies in refining their codes and industry practices for offshore turbines to make them fit for purpose.

UNCHARTED WATERS

But the fact is that we are entering proverbial uncharted waters. Although the technology is relatively simple — wind turbines have been around quite a long time — the logistics would stretch any organisation to the limit. No one has tried before to build or underwrite offshore wind energy on anything like this scale. The challenges of construction, connection, operations and maintenance, as well as access from either vessels or helicopter, make it unpredictable both in terms of cost and what might go wrong. Any given project can be disrupted by a series of factors including site-specific conditions, inclement weather delays, data management, availability of specialist construction vessels and market rates.

Offshore and onshore wind farms are different in many respects, and so the usual ways of thinking about the electrical aspects may not be appropriate. Clearly, costs will be higher than on land. However, reliability and availability are also much more important, because faults may be more frequent and could take much longer to locate and repair — with obvious cost implications. Furthermore, if one turbine fails to function, it could potentially knock out up to 20 others.

So, where does this leave insurers? Key lines include construction risk, faulty design, business interruption and product liability, loss of advance profit, professional indemnity and third-party liability. Of these, construction remains the biggest area and the one most likely to generate losses. We have already seen the market evolve tailored wordings and variations on industry standard Construction All Risks (CAR) policies for the specific purpose of constructing offshore wind farms. We have also witnessed the refinement of risk management procedures highlighting the specific challenges of erecting offshore wind turbines in shallow water.

A prime example of a potential worst-case scenario for business interruption would be the failure of the main onshore substation that distributes the total power production to the national grid. A similar incident has already taken place elsewhere in Europe. Were it to happen to the London Array, with an estimated output of 1,000 megawatts, the costs would mushroom in terms of business interruption.

The London market is famous, of course, for its appetite for large and difficult risks — and it will meet the challenge. Big as they are, the potential losses will be on a much smaller scale than the offshore oil sector. Inevitably, though, there will be losers as well as winners. Those underwriters who truly understand the risks and select them objectively, rather than simply jumping on the green bandwagon, will prosper. And they will also play a vital role in giving the UK a chance to meet its target of 15% of energy from renewable sources.

A version of this article first appeared in Post Magazine in April 2010.

BIG ORANGE XVIII: COLLISION IN EKOFISK FIELD

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One of life's enduring lessons is encapsulated by the saying 'we learn by our mistakes'. We all make mistakes and generally we do learn from them. Companies should be no different. However, there is evidence that the offshore industry continues to fail to learn from its own direct mistakes or near misses, and also does not learn from the 'mistakes' of others. The *Big Orange XVIII* collision in the Ekofisk field in June 2009 is one such event and is a lesson that we should all learn from.

At the Standard Club, we have identified through our Member Risk Reviews and condition surveys that significant numbers of companies do not have:

- effective accident or near-miss analysis
- effective past incident follow-up
- effective internal audits

If effective accident analyses and/or near-miss analyses are not carried out and followed by effective internal audits, then lessons will not be learnt.

In addition, the club has identified that complacency and lack of leadership is often an issue in major incidents. This is mentioned in *The Human Element – a guide to human behaviour in the shipping industry*, which was recently published by the MCA (Maritime and Coastguard Agency www.mca.gov.uk) and to which the club contributed. These were issues prevailing in the *Big Orange* incident.

The Norwegian Petroleum Safety Authority (PSA) published a comprehensive report in October 2009 about the collision of the well service ship *Big Orange XVIII* with the Ekofisk 2/4-W platform.

The Ekofisk field is a group of offshore units located within the Norwegian continental shelf.

DESCRIPTION OF EVENTS

The ship was engaged to carry out a well stimulation operation in the Ekofisk field off the Norwegian coast. The ship was approaching a collection of Ekofisk facilities when the ship collided with one of these facilities whilst its propulsion systems were reportedly 'out of control'. Fortunately no-one was hurt either on board the ship or the facilities, but the potential loss of life and damage was enormous.

The bridge was manned by the second officer (who had just joined the ship five days previously) and the master.

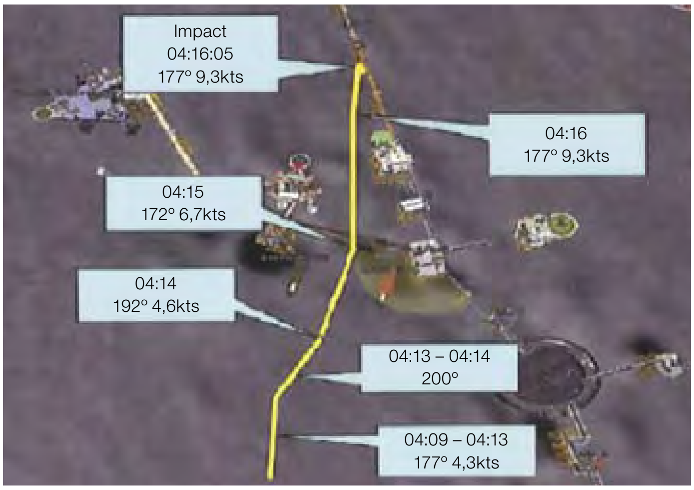
Timeline

03.40 hrs	*Big Orange XVIII* called by Ekofisk radar control to prepare for well stimulation.
04.00	Master on the bridge and takes over 'the con' (is in command of the ship). Ekofisk contacted to allow permission to enter the 500m safety zone. The steering gear mode was changed from 'auto pilot' to manual steering.
04.02	The telephone on the bridge rings with an outside call from the charterer's representative on the installation. The master resets the steering back to auto pilot mode, leaves the steering position and goes to the radio room to answer the telephone call. The radio room is separate to the bridge. The brief call lasted for about 30 seconds and the master returned to the steering position. However, he did not reactivate the manual steering. The ship continued in auto pilot.
04.06-08	The ship is at this point proceeding at 8.4 knots
04.11	The ship is given permission to enter the 500m safety zone.
04.13	The ship is still in auto pilot mode. The master reduces speed on the main engines but is now aware that the ship is not responding to manual helm movements and to thruster instructions. (Note: when the steering is operated in auto pilot mode, manual steering is obviously ineffective and with this ship's particular set-up, the azimuth thrusters could not be operated in manual mode unless the steering was in manual).
04.14-15	The *Big Orange XVIII* is now inside the safety zone and passes under the Ekofisk 2/4-X passenger bridge. The master tries to stop the ship by reversing the azimuth thrusters through 180 degrees.
04.16	Out of control, the *Big Orange XVIII* passes Ekofisk 2/4-FTP and *COSL Rigmar* (accommodation unit) at nearly 7 knots and between 4 to 10m. Master informs Ekofisk radar that the ship had lost power (this was not in fact correct).
04.17	*Big Orange XVIII* collides with the Ekofisk 2/4-W water injection facility at 9.7 knots.
	After the incident, the ship was eventually able to move off under its own power and steering.

Significant material damage was caused to the Ekofisk 2/4-W injection facility.

Even though there were no injuries or pollution, the PSA classified the collision as a major accident because the facilities' integrity was endangered and there were potential multiple personal injuries on the other facilities.

The potential consequences resulting from the size and speed of the ship could have resulted in a collision energy that was six times higher than the facilities were constructed to withstand.



The course of Big Orange XVIII based on radar plot from Ekofisk Radar and AIS

Damage to Ekofisk 2/4's load-bearing structure, conductor and riser (source: ConocoPhillips)

POTENTIAL CONSEQUENCES

The potential consequences resulting from the size and speed of the ship could have resulted in a collision energy that was six times higher than the facilities were constructed to withstand. The jack-up accommodation unit *COSL Rigmar* has the capacity to accommodate up to 290 personnel and the report considers it unlikely to have withstood an impact collision at the speed at which the *Big Orange XVII* was travelling.

The facility Ekofisk 2/4-Q, which had 120 personnel on board would have sustained extensive damage. The 8-inch gas pipeline running from the Ekofisk 2/4-C to 2/4-13 units could have been damaged, resulting in fire and gas explosions with loss of life.

It was by pure chance, and nothing more, that the ship hit an unmanned unit with only material damage to the ship and unit. The ship as can be seen from the attached photo sailed through the field and could have impacted any one of the nearby installations. The potential for loss of life was considerable.

PROBABLE VIOLATIONS OF PSA REGULATIONS

- field operator had not complied with requirements to monitor activity within the 500m safety zone. Speed restrictions within the safety zone were not complied with
- proposed measures following a similar collision in 2005 had not been fully implemented, namely:
  - informing shipping companies of field measures to be implemented
  - implementing the safety zone entry requirements

IMPROVEMENT RECOMMENDATIONS (OBSERVATIONS WHERE FLAWS WERE IDENTIFIED WITHOUT SUFFICIENT PROOF TO CONFIRM VIOLATION OF REGULATORY REQUIREMENTS)

- field operator's safety management system relating to the entering of vessels was not sufficiently complied with

OTHER COMMENTS

- division of responsibility/assignment of duties on the ship's bridge were insufficient
- the second officer's competence was not ensured
- the second officer was new to the role and had not received the required training in accordance with the shipping company's own guidelines (or to normally accepted ISM familiarisation procedures)
- the ship did not comply with the hours of work/rest regulations
- the following guidelines and regulations were not complied with: Norwegian Safety at Sea Act, IMO ISM Code, STCW regulation, NWEA (North West European Area) guidelines for the safe management of offshore vessels.

Ekofisk 2/W4-W

LESSONS LEARNT

Reference was made in the report specifically to two earlier similar incidents in 2004 and in 2005, which if the lessons learnt had been taken on board may have prevented this incident from occurring.

The first involved a ship that collided with a drilling facility, where the officer of the watch (OOW) had not entirely complied with the 500m safety zone checklist before entering the 500m zone. The auto pilot was not deactivated before entering the safety zone. The OOW was convinced that the auto pilot was deactivated.

The second incident in 2005 related to a supply ship colliding with a unit in the same field. The field operator's internal investigation recommended several measures, including checking the use of the auto pilot prior to entering the 500m safety zone.

The NWEA guidelines, good practice and common sense dictate that a stringent procedure, using a formal checklist, should be carried out before the ship enters the 500m safety zone. The club has also seen significant claims arising from the failure to carry out checks before entering the 500m safety zone and not adhering to field and company procedures. These have included:

- failure to test DP (dynamic positioning) systems before entering
- failure to properly investigate DP and manoeuvring system alarms
- failure to ensure all manoeuvring systems are tested
- failure to test steering systems
- failure to reduce to a safe speed
- failure to ensure sufficient and adequately trained/familiarised personnel are on the bridge
- failure to ensure command and control of the bridge has been formally agreed

All companies should reinforce their safety zone entry procedures and ensure that they are diligently followed. The additional lesson learnt is that time and resources should be provided so that personnel can be fully familiarised with the equipment they are operating. A number of major incidents have resulted from personnel not being familiar with the equipment being used.

This incident was 'third time unlucky', it should not have happened; everyone should learn from their own and other people's mistakes.

All photos have been taken from the PSA report available on its website.

P-57 FPSO – JUBARTE FIELD

This article first appeared in SBM Offshore's magazine Currents. For more info please visit www.sbm.com or contact currents@sbmoffshore.com

The P-57 will be the first turnkey FPSO to be supplied by SBM Offshore to Petrobras. The formal contract was signed on 1 February 2008. This project is unique, being the first contractor-supplied FPSO to achieve 65% Brazilian content. After a 35 month schedule, the FPSO is due for delivery and first oil at the end of 2010.

Over the first 24 months, P-57 was the project that never slept. Project teams from around the globe worked around the clock. Truly an SBM Offshore Group project, team members in Monaco, Schiedam, Houston, Rio, and Singapore have participated in the success of P-57.

TECHNICAL DETAILS

The *P-57 FPSO* is a spread moored vessel and has the possibility to offload both forward and aft. It is the largest FPSO that SBM Offshore has ever built with a daily production capacity of 180,000 barrels of oil per day and total gas compression of 71 MMscfd (million standard cubic feet per day); the topsides are also an impressive size weighing 14,500 tonnes. The spread mooring arrangement was also a technical design challenge with 21 mooring lines of varying lengths.

Embracing new vendors and yards in Brazil with their own working methods, design and fabrication features was one of the largest engineering tasks for the successful execution of the *P-57 FPSO* project. Petrobras' professional and energetic engineering project team was effective and result driven, and formed a close bond with the SBM team.

As for the execution of work, four yards were contracted: two in Singapore (Keppel Shipyard and Dynamac) and two in Brazil (UTC Engenharia and BrasFELS). Keppel Shipyard and BrasFELS are sister companies from the Keppel Group.

Deck of the *Accord* vessel at Keppel Shipyard, Singapore

SINGAPORE

On 14 September 2008 the *Accord*, the original ship used for the *P-57*, arrived at Keppel Shipyard in Singapore. The FPSO represents the sixth built jointly between Keppel and SBM Offshore for Petrobras.

The main refurbishment of the hull took place at Keppel shipyard; it was reinforced with 1,600 tonnes of steel. The topsides modules were completed and integrated as follows: the Gas Compression, Power Generation, Local Equipment Room, Piperack and Oil fiscal metering skid (the latter being built in Brazil and shipped to Singapore for integration). With no critical carry-over, the vessel left Singapore on 9 March 2010 to commence the second phase of the project in Brazil.

BRAZIL

While the *P-57* vessel was in Singapore, in parallel to the construction of the 10 modules, at UTC yard (Niteroi) and BrasFELS (Angra dos Reis), the procurement team was actively working with Brazilian subcontractors. One of the unique aspects of this project is the 65% local content, which is a first for both SBM and Petrobras for a contractor-supplied unit. Both companies are hoping that this unique business model will be a benchmark for future FPSO projects in Brazil.

P-57 at BrasFELS, Angra dos Reis Brazil

After a 40 day journey, on 22 April 2010 the *P-57 FPSO* arrived at BrasFELS in Angra dos Reis, for the final integration and commissioning phase. All modules were finally lifted on board the FPSO in mid-June.

STILL TO COME

Upon Petrobras' request, SBM targeted to deliver the *P-57 FPSO* in October, two months before the contract delivery date. The new plan, called the "acceleration plan", includes implementation of the necessary resources and facilities for the yard activities to run faster. The following actives have been accelerated:

- welding and connection of all topside modules and equipment skids that were fabricated in Brazil;
- integration of all topside modules and equipment skids fabricated in Brazil including hook up of all connections (electrical, instrument, piping, structural) in line with the design documents;
- hydro and leak testing of the hook up spools to all BrasFELS installed topside modules;
- assistance for the commissioning of the FPSO;
- application of final coating systems and touch up painting where necessary (vessel main deck, welded structures); and
- delivery of the FPSO unit afloat along quayside ready for sail-away to the offshore installation site.

Over the past months, SBM and BrasFELS have built a real partnership that allows both companies to work with the same goals in mind: a joint success on *P-57*. This has been achieved mainly due to the integrated management team from all levels of the BrasFELS and SBM organisations.

P-57 is a truly international project, with team work being essential, requiring high energy, expertise, efficiency and the will to get the job done.

HELICOPTER INDEMNITIES

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Local authorities often provide helicopter Search and Rescue services, but members are able to contract on commercial terms for the carriage of ship's supplies, pilots and passengers.

Such contracts may contain onerous indemnities in favour of the helicopter operator and members should consult with the club managers for guidance where helicopter/ship operations are planned.

The contract either should not contain any indemnities or such indemnities should only be in respect of loss or damage arising out of the member's breach of law.

If the contract does include indemnities by the member in favour of the operator, then care should be taken to ensure that they are no more favourable to the helicopter operator than the old KLM Rotterdam contract. Under those terms, the helicopter operator agreed to be responsible for damage to or loss of the aircraft. It also agreed to be responsible for all third-party damage caused as a result of its operation, other than liabilities caused by the member's sole negligence or default. The helicopter operator can limit its liability to $30m and the member agrees to indemnify it to the extent that claims exceed that amount.

Members should comply with the ICS *Guide to Helicopter/Ship Operations*. Compliance with this practical guide does not guarantee club cover and members should seek the club's approval to the terms of any contract with a helicopter operator.

CRANE HAND SIGNAL POSTERS

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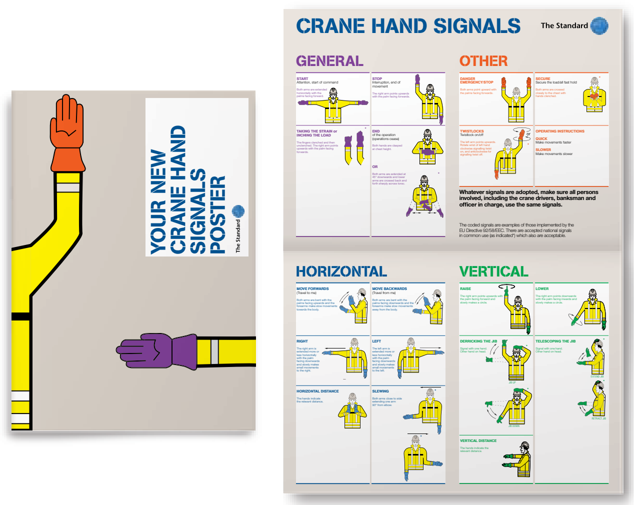
The club's recent edition of *Standard Safety* was a special edition focusing on personnel transfer using ship's cranes. The transfer of personnel at sea or offshore has been practised for a long time. In the past, it was usually done only in an emergency, but the practice has been carried out normally offshore from oil platforms and construction units. This has decreased with the onset of helicopter transfers, but it is still regularly practised in some areas.

To accompany the July 2010 issue of Standard Safety, we have produced a poster on crane hand signals.

Copies of the poster can be viewed on the club's website: www.standard-club.com

If you would like copies of the posters, please email me: chris.spencer@ctcplc.com



CONTRACTUAL CLARITY

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The English court has confirmed the construction of standard language used in a drilling rig charter between BP Exploration Operating Company Ltd and Dolphin Drilling Ltd ([2009] EWHC 3119 (Comm)).

During contractual negotiations, the day rate for the semi-submersible rig, the *Byford Dolphin*, was agreed at $410,000 in September 2008 for a three-year contract, with drilling operations commencing in the first quarter of 2010.

BP wished to terminate the contract prior to the commencement date and sought a declaration from the court that it was entitled to terminate the work or the contract at any time for a number of specified reasons, including its own convenience, and that its liability for payments to Dolphin would only include sums due for work done prior to termination. The commercial implications for Dolphin of the termination were considerable.

Dolphin argued that there was no contractual entitlement to terminate the agreement for BP's convenience until after the commencement date and that any purported termination would be a repudiatory breach leaving Dolphin with the remedy of damages, including a claim for loss of profits.

S22.1 of the contract stated:

"The COMPANY shall have the right by giving notice to terminate all or any part of the WORK or the CONTRACT at such time or times as the COMPANY may consider necessary for any or all of the following reasons:

(a) to suit the convenience of the COMPANY."

Dolphin argued that something had gone wrong with the language of the contract and that a reasonable person would have understood it to be read subject to an implicit proviso that this right could only be exercised after the commencement date. The court had difficulty with this approach. The relevant contractual provision is based on the industry's standard LOGIC Conditions of Contract. The fact that these conditions have been used by the oil and gas industry since 1997:

"…. greatly undermines the suggestion that an open ended liberty to terminate at the convenience of the charterer both before and after the commencement of the drilling operations makes no commercial sense."

A number of other scenarios permitting termination were accepted as not being subject to a requirement that they occur before or after the commencement date. The court concluded that:

"The outcome (in the aftermath of an unexpected financial crisis) may be highly unattractive from Dolphin's perspective. But it arises from a standard term…. In my judgment whether the motivation for termination is the fall in the market on the one hand or, say, the absence of drilling opportunities in the designated area on the other, it is not made out that the consequences are commercially absurd."

The fact that the construction of a contract would lead to a commercially unattractive outcome for one party should not then mean that such a construction should be rejected as being irrational. The parties used standard industry terms in a formal document to regulate their relationship; whilst acknowledging that the result was very favourable for one party, the court was not prepared to depart from the ordinary meaning of the language used.

Thankfully, litigation upon the construction of industry standard wordings is rare. It is recommended that members closely examine their contractual terms and ensure that their pre-contract risk/benefit analysis includes contingencies such as early termination.

GULF OF MEXICO: WRECK REMOVAL – A SALVOR'S PERSPECTIVE:

The 'Big Daddy' was a 24-inch gas pipeline that reportedly transported gas worth $1bn per month.

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Hurricane Katrina devastated New Orleans and wreaked havoc across a large section of the Offshore Oil Patch on and prior to Monday August 29, 2005. The local SMIT SALVAGE office and warehouse is located in Houston, Texas. That Monday, Houston experienced a typical hot summer day as the Louisiana coast was being dealt a catastrophic blow. The first marine casualty calls received were on Tuesday, the day after the storm made landfall. Soon after, as the world was dealing with the news, the Smit office became very busy working with bluewater parties from Japan, Greece and Italy, and offshore interests from the US. Emergency response contracts were awarded and dealt with first and then a very exciting period of complicated wreck removal work ensued.

Wreck removal in the United States Gulf of Mexico (USGOM) can be an overwhelming process for those responsible. A significant and unique consideration is the incredibly high number of stakeholders due to the extensive oil and gas network, subsea infrastructure, potential third-party damages, and regulating bodies and their interwoven roles.

The USGOM entire outer continental shelf is divided into blocks that are leased to various parties for a relatively long term from the US government for oil and gas exploration. The government agency overseeing the leased block is the Minerals Management Service (now Bureau of Ocean Energy Management, Regulation and Enforcement). Lease block holders are required to return the lease block in the same condition that it is received in (i.e. bottom clear and wreck-free). The lease holder can be a significant stakeholder during a wreck removal case especially if the lease has been developed. An interesting situation exists when wreck removals occur outside territorial waters. Voluntary wreck removal is not typically insured. What is voluntary, what is mandatory, and who is legally responsible and recognised to issue the wreck removal order? Frequently, on the outer continental shelf beyond territorial waters, it is the leaseholder who demands the wreck removal. Often, marine offshore drilling units carry typical P&I insurance cover during sea transits, which clearly covers wreck removal when required by law or when the wreck is a hazard, but when on site working, the insurances change to a blend of energy sector and marine coverage which may be less clear cut. Common sense has prevailed in all of the cases that we have been involved with; however, the complexities from time to time have had to be considered. In one case we are familiar with, the excess liability coverage was called upon, which it has since been suggested was like fitting a round peg in a square hole: force it hard enough and you will make it fit.

Parties with right–of-way passage through leases, such as pipeline companies, are another example of a significant stakeholder. We have first-hand experience of a number of scenarios in which pipelines suffered from wrecks landing on them, resulting in undamaged, damaged or completely severed pipelines. In one of the more challenging situations, we faced a wreck that sank and was sitting on top of nine pipelines where the 'Big Daddy' of all was from an otherwise innocent party. The 'Big Daddy' was a 24-inch gas pipeline that reportedly transported gas worth $1bn per month. Eight of the nine pipelines were shut in relatively without fanfare, but the 'Big Daddy' was pressure-tested and restarted days after the sinking with the wreck still on top of it! Co-ordinating this operation and removing the wreck section as planned was a particularly rewarding experience operationally for the salvage team and financially for all stakeholders.

From time to time, sea experiences occur that differentiate themselves from those in our portfolios. Last year, we were called to an emergency response case for a tanker laden with 160,000 mt of crude oil that experienced an immediate and significant list while approaching an offshore lightering area. The casualty was about 70 miles off the coast of Galveston and experienced water ingress into a number of port-side double hull tanks, posing a huge environmental threat. Once on site, we stabilised, lightered, inspected the casualty by remotely operated vehicle (ROV) and investigated the site where a subsea collision was suspected. Much to our surprise, we found a capsized sunken rig that had been missing since Hurricane Ike. The rig was nearly 100 miles from where it was lost and far from where an exhaustive search for it had been conducted. The precarious lurking of this wreck just below the surface, in a designated offshore tanker lightering area, was incredible.

This summer, we are engaged in the wreck removal of this rig, which upon completion will close another wreck removal chapter in the USGOM. Finding this one will be a sea story that will withstand the test of time.

ASIAN OFFSHORE

With offices in the heart of Singapore's business district, Standard Asia is well placed to take advantage of future industry growth.

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Standard Asia, the Standard Club's Singapore based P&I club, has been underwriting Asian offshore business since it was set up in 1997, during which time the book of business has greatly expanded. It is also more varied; in 1997, it was dominated by supply boats, but now includes floating production storage and offloading vessels, drilling rigs and construction units, with the growth of Standard Asia's offshore business mirroring that of the upstream energy industry in Asia and Australasia.

With offices in the heart of Singapore's business district, Standard Asia is well placed to take advantage of future industry growth. It is well known that Singapore has been highly successful in positioning itself as a global maritime hub, and the Maritime and Port Authority (MPA) works tirelessly to attract and support a core group of shipowners, operators and maritime service providers. Included amongst these are the some 110 offshore related companies that today are established in Singapore, while there are presently 406 offshore service vessels under the Singapore flag.

The Singapore offshore cluster has attracted a number of leading players in international offshore shipping operations, including companies from Norway, the US and elsewhere. Examples include Tidewater Marine, the Swire Group, Bourbon Offshore, DOF, PGS, Farstad, Seadrill, Prosafe and Vroon. In addition to the foreign players, the cluster also comprises numerous local offshore vessel companies that have expanded globally, such as Ezra, Swiber, POSH, Miclyn Express Offshore and Pacific Richfield Marine, amongst others.

These offshore vessel operators are supported by a comprehensive cluster of shore-based businesses and infrastructure, including numerous yards specialising in offshore vessel construction and repair, by the upgraded Loyang Offshore Supply Base and the new Marine Centre at Tuas, which will be operating by the end of 2011. There are also a number of supporting service providers such as equipment design companies. Many of these companies will be members of the Association of Singapore Marine Industries (www.asmi.com).

Commercially, offshore support vessel owners and operators also have access to a host of major shipbrokers, shipping and offshore financing banks, marine insurers and law firms. Virtually all the international maritime law firms have a presence in Singapore, and Lloyd's Asia now has 16 syndicates, including a number underwriting energy risks. In addition, the Singapore Chamber of Maritime Arbitration offers an arbitration framework in many ways similar to LMAA (www.scma.org.sg).

Recognising the need to accommodate the growing number of ships involved in offshore oil and gas activities, the MPA amended the Merchant Shipping Act to allow the Singapore Registry of Ships to register 'offshore industry mobile units' that comply with the IMO's Mobile Offshore Drilling Unit code. Today, the Singapore Registry of Ships' book of offshore vessels includes seismic survey ships, anchor handling tugs, anchor handling tug supply vessels and platform supply vessels, and various offshore units such as semi-submersible rigs, drill ships, jack-up rigs, FPSOs and floating storage and offloading vessels, accommodation platforms and construction vessels.

International shipping companies with established worldwide networks, a strong track record, demonstrable business plan and a commitment to expanding their shipping operations in Singapore may apply for Approved International Shipping Enterprise status. Companies under the AIS scheme enjoy tax exemption on qualifying shipping income for 10 years.

A number of local organisations support the work of the offshore sector in Singapore. Samantha Lee of Standard Asia is a member of the Offshore Services Committee of the Singapore Shipping Association (www.ssa.org.sg), which has provided owners and operators in Singapore with a platform to debate and drive initiatives for this sector. The Singapore-based Marine Offshore Oil and Gas Association is another relevant association.

All in all, Singapore is proving itself highly attractive as a centre for companies involved in the offshore oil and energy industry in all its forms. We have no doubt that the offshore cluster in Singapore will continue to grow and thrive, and Standard Asia looks forward to being part of its future expansion.

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